Transmission System Reliability Performance Metrics Requirements

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Technical Update, December 2003

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EXECUTIVE SUMMARY

Transmission availability has become the significant indicator of overall transmission system operational health, due to increased utilization of the transmission system, growth of deregulated energy wholesale markets, and decreased investment in new transmission assets. Availability trends reflect the increasing dependence upon transmission assets from a technical and market perspective.

Presently availability metrics lack comparability due to the non-standardization of underlying data collection methodologies and localized practices. Between-system reliability comparison is diminished by variations in basic definitions, terminology, and application to reporting practices. Most transmission system availability metrics lack sufficient sensitivity to determine equipment availability impacts. Few indicators are sufficient to justify or defend reliability investment and maintenance decisions.

The industry has evolving business needs which require immediate attention toward transmission reliability performance metrics including:

- System reliability performance and market interactions
- Consolidation & corporate standardization
- Divergent needs of transmission-only systems' from traditional customer based indices
- Global need for transmission system reliability performance comparison leverage

However in the United States, ongoing issues continue to delay necessary action including:

- National regulatory direction in this area continues to be delayed due to governance issues
- State regulators anticipate federal action and are thus hesitant to take prior action
- Insufficient industry dialog on transmission performance metrics standardization
- A general lack of interest in leveraging global accomplishments in transmission regulation

Despite these issues, the transmission industry needs meaningful performance metrics today.

Results and Findings

This report summarizes the need for a broad industry consensus to standardize the development of transmission reliability performance metrics and their underlying definitions and applications to power delivery processes. The report draws from significant industry expertise that has clearly expressed the benefits of these objectives as:

- Increased quality of industry reliability comparisons, i.e., benchmarking
- Increased transparency and accountability of system reliability performance and market interactions.
- Ensured equity of performance based regulation (if enacted)

Challenges and Objectives

Transmission managers in all major transmission power delivery processes will benefit from the assessment of industry reliability performance needs, underlying causes of non-standardization, and improvement initiatives recommended by broad industry professional expertise with similar goals and responsibilities. The project objectives enable managers to set meaningful strategic system performance goals, to optimize maintenance tasks and asset management strategies, improve the accuracy of system planning modeling, to improve outage scheduling, to improve reliability prioritization, and to improve market decision analysis.

Applications

These objectives improve the quality of all major transmission power delivery processes including: strategic planning, maintenance, asset management, system planning, operations, reliability, regulatory, and market participation.

EPRI Perspective

The timing of project participation is critical in light of pending mandatory reliability rules in the wake of the 2003 blackout and subsequent fallout. In addition as industry consolidation continues transmission owners and regulators need consistent and meaningful transmission reliability performance metrics for improved decision making.

Approach

The report discusses underlying issues that impair the quality of existing transmission reliability performance comparisons. The impacts of those issues to industry fundamental system reliability principles and to the integrated power market are discussed. Resulting benefits of an

industry directed consensus project are enumerated against these two areas. The results of an initial workshop are discussed as evidence of growing demand for industry changes. This report describes a scope of work and schedule, moving forward to include workshops, participant review, site assessments, and data methodology validation to accomplish a set of objectives defined by workshop participants within the expected timeframes of regulatory directives.

Keywords

Transmission Reliability

Transmission Availability

Transmission Regulation

Transmission Performance Metrics

Strategic Goals

Asset Management

Open Access

PREFACE

The purpose of this section is to acquaint the reader with the project history relevant to this technical status report.

Prior Publications

The project was started approximately three years ago and has other previous reports available upon request of the EPRI Project Manager (EPRI Report # 1001971 – Grid Equipment Reliability Study). A Functional Requirements document for this project was completed in December 2002 (EPRI Report #1001827). The scope of the document was limited to substation equipment definitions and categorizations required to integrate major transmission equipment to transmission unit definitions and thus relate equipment reliability impacts to overall transmission grid reliability performance.

Initial Funding

The project was not fully funded in 2003 under EPRI base funding and was released for Tailored Collaboration Funding in March 2003. Insufficient interest materialized for the proposal it is estimated retrospectively because: (1) the pricing was too high and thus counterproductive to participation requirements needed for broad consensus; (2) the scope was not aligned with specific industry demand.

As a result limited EPRI base funding was provided to extend the time needed to establish participant requirements. The first activity was a Combined Working Group Meeting in May 2003. A group of approximately ten systems were represented at this meeting. The scope of equipment metrics for the project was presented and discussed within the group. While the group made no commitment to the project several general requirements were proposed. These requirements included a limit to project scope and detail and a review of global transmission regulatory environments for existing definitions and metrics. The project management team also identified that additional industry marketing methods were necessary in order to achieve the project's goal of broad industry participation.

Modifications

An EPRI list server was chosen as a method to address this issue. An FTP site was established to provide files to participants. Direct marketing was conducted to broadcast the project and to invite participation through the list server medium. In addition a Web-Ex conference was held in August to reach and inform interested participants. These tools achieved a significant increase in industry awareness as the list server grew to one hundred individuals from over fifty organizations throughout the world.

While the list server and FTP technical setup was in progress, industry research was conducted of existing regulatory environments. Initial research findings were then posted as files to the participants via the FTP site.

Workshop

A project workshop in October was met with equal success as the subject matter workshop was held separately from other EPRI meetings and attracted thirty participants from twenty-five organizations. Participants represented the diverse industry interest in transmission reliability performance metrics. Participants included individuals from investor owned utilities, public power entities, vertically integrated and transmission only companies, regional reliability council staff, independent system operator staff, and state public service commission staff.

The October workshop was well received by attendees as meeting evaluation surveys indicated a high level of satisfaction with the workshop attendance, diversity, content, interaction, and facilitation. The results of workshop presentations, surveys, and group exercises were electronically integrated and redistributed to the participants and posted to the greater list server community.

Summary

This document draws upon the integration of those activities, experiences, correspondence, conversations, research, and workshop results referenced in this preceding section of text. This document is intended as a status report of the project and more importantly of the potential future direction. It does not represent an absolute and final consensus on the subject matter by any of participating systems, organizations, or individuals. It does represent a general sense of direction that participants (in direct marketing discussions, on the list server medium, and during the project workshop) expressed for the future of the project.

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1 INTRODUCTION

Transmission availability has become the significant indicator of overall transmission system operational health, due to increased utilization of the transmission system, growth of deregulated energy wholesale markets, and decreased investment in new transmission assets. Availability trends reflect the increasing dependence upon transmission assets from a technical and market perspective.

Presently availability metrics lack comparability due to the non-standardization of underlying data collection methodologies and localized practices. Between-system reliability comparison is diminished by variations in basic definitions, terminology, and application to reporting practices. Most transmission system availability metrics lack sufficient sensitivity to determine equipment availability impacts. Few indicators are sufficient to justify or defend reliability investment and maintenance decisions.

Industry Background

Regulation

Since the United States transmission market is regionalized, transmission network performance measurement varies across regional jurisdictions. Traditionally state regulation has been distribution electric power delivery focused. In addition each state is locally focused but monitors other states and federal authorities for transmission regulatory precedence.

The traditional realm of the states regulation may be inadequate for the newly formed for-profit transmission entities. These entities often cross state boundaries and regulatory jurisdictions, thus complicating state governance. Public power transmission entities are also often legally exempt from state jurisdictions.

In recent years US federal transmission regulatory authority has been walking a tightrope of balancing states' rights and pre-emption concerns. In addition the several industry crises in the past five years have left reliability performance regulation on the sidelines to governance and market participation issues. These issues are the subject of ongoing debate which requires additional time to resolve.

In addition the industry is still in the midst of an investigation by a North American investigative team into the largest transmission system blackout in history during August 2003. The resulting recommendations will inevitably bring changes to the industry and to the status of reliability and performance regulatory requirements, but these changes will require additional time.

Industry Consolidation

The deferral of these decisions runs headlong into an industry in the midst of continued consolidation. As this continues corporate mergers operate several transmission systems across state lines and under several state regulatory environments. Merger benefits often are accomplished by an optimized allocation of resources based upon an underlying standardization of transmission performance from subordinate entities.

These corporations often have globally based operations. These other markets have regulatory models from which to consider additional performance metrics which range from overall system performance measures to major equipment performance measures. However there is a need increasingly expressed to have standardization of transmission reliability performance metrics for the North American market.

Transmission-Only Segment

In addition the transmission industry has witnessed the emergence of for-profit independent transmission companies. These companies increase the number of non-vertically integrated transmission organizations, including public power entities such as Tennessee Valley Authority, TVA, Bonneville Power Authority, BPA, and Western Area Power Administration, WAPA, to name but a few. These organizations need to demonstrate financial accountability to the public and private sectors. Transmission reliability performance metrics function as an essential indicator of management's performance to these financial and social-political obligations.

The transmission-only industry segment needs are diverging from traditional vertically integrated systems. This segment of the industry is unsatisfied with traditional customer based indices such as SAIFI, SAIDI, and CAIDI due to the predominant focus of these metrics upon impacts to customers whom they do not know, own, or see.

Calculation of such indices also has practical limitations when the customer data needed must be supplied by a load serving entity. Often these load-serving entities refuse to supply such information because of a general a fear that transmission only companies may use that information in a discriminatory manner, i.e., such that transmission service reliability is dependent upon delivery point customer density to elevate restoration efforts or improvement allocation, etc.

In addition to customer information issues, there is a general difference in how these companies view "the customer" and "the delivered product" from the load serving entities. Quite expectedly the definition of successful transmission performance is seen through another lens. Yet even within fully integrated utilities, managers often have transmission-only responsibly and share the dissatisfaction with traditional customer based indices: (1) to equitably reflect transmission system performance and the level of proficiency with which they are managing those assets, (2) and the present ability of traditional performance metrics to permit consistent between system comparisons.

Market Impacts

The growth of the wholesale deregulated energy markets has resulted in new economic impacts to market participants. These demand accountability and transparency of transmission system operations and maintenance. System reliability performance includes transmission facility unavailability due to planned maintenance and operations. Economic consequences of the unavailability potentially impact other market participants

Market activity, such as the oversubscription of transactions can result in transmission system reliability impacts, such as overloaded transmission lines. In addition power transactions between non adjacent transmission systems can result in unintended or parallel loop flow reliability issues such as unintended overloads in adjacent systems, economic consequences such as interruptions to firm transmission service, or displacement of generation in adjacent systems.

In addition when system unavailability occurs for non-security based, i.e., discretionary reasons; some accountability is required to ensure that there is no market power incentive. Where congestion costs are socialized, accountability is needed to ensure that unavailability for sake of private profit is not at the expense of socialized cost and risk. In summary, accountability is necessary to distinguish between market manipulation and responsible grid maintenance.

Industry Summary

The industry has evolving business needs which require immediate attention toward transmission reliability performance metrics including:

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However in the United States, ongoing issues continue to delay necessary action including:

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Despite these issues, the transmission industry needs meaningful performance metrics today.

Remaining Chapters

The remaining chapters examine areas where consensus is required as a prerequisite to aligning consistent methodologies and metrics that support evolving business objectives and long standing fundamental transmission reliability principles. These chapters include: underlying definitions of transmission facilities and availability, specific applications of transmission reliability performance metrics, and specific details of a proposal for an ongoing project scope and its benefits to the industry. Appendices summarize: 2003 project activity, results of a project workshop, and summary comparisons of existing measurement systems.

2 DEFINITIONS

Transmission Facilities

The definition of transmission facilities itself is an area where industry consensus has not been reached. There are some industry guidelines but they are independently interpreted. The resulting impact has widespread consequences to decision making throughout the industry.

A functional approach is stipulated by FERC under the “seven factors” test. With this interpretation no voltage class minimum criteria is applied. Thus facilities below 30kv are functioning as transmission for some systems. MAIN/MAPP reporting guidelines stipulate that 69kv and above are transmission. NERC defines the bulk transmission system as facilities generally equal to or above 230kv. Canadian Electric Association reporting practices collect reliability performance for facilities at 60kv and above.

Functional transmission facility interpretations clash with voltage class interpretations commonly held by the technical community within the industry. The potential for additional distributed wholesale generation facilities on lower voltage systems or “distribution” networks in the future may, using functional approaches, further complicate the distinction between transmission facilities.

While there are similar functional attributes between sub-transmission facilities and generally higher voltage facilities transmission, the technical comparison is considered apples to oranges. The underlying planning criteria differences may include n-1 vs. an n-0 contingency basis difference. In addition the system constituent elements have material design differences such as the basic insulation level, transient withstand capabilities, corona properties, structural strength, etc. These differences support voltage class comparisons as a credible basis within a transmission performance standardization schema.

In closed benchmarking formats, the undisclosed interpretations of underlying transmission facilities included can limit the value of the resulting comparisons or suggest misleading conclusions. For example the inclusion of sub-transmission facilities along with transmission facilities can skew results. When regulatory or internal corporate goals are based upon the results of an apples-to-oranges transmission performance comparison bad public policy or flawed internal incentives is an unintended outcome. Internal investment and maintenance decisions based upon flawed comparisons suffer similar consequences as well.

Reliability Definitions

The term "reliability" and its meaning is another area in which the industry is not in consensus. The resulting interpretations limit the comparisons of transmission reliability. The generalized interpretive rift is between those who consider reliability as limited to forced and/or unplanned interruptions versus those who include all unavailable periods as part of the reliability context.

NERC defines reliability as: The degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system adequacy and security[1].

NERC defines adequacy as: The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements[2].

NERC defines security as: The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements[3].

NERC defines availability as: A measure of time a generating unit, transmission line, or other facility is capable of providing service, <u>whether or not it is in service</u>[4]. (Underlined here for emphasis)

The definition of system reliability takes into account all unit outages and is therefore dependent upon transmission facility availability. Yet it is more comprehensive since reliability is the overall capability to supply, i.e., the design basis, integrated with the availability of its constituent elements. Therefore when examining only the forced and unplanned outages, i.e., the unexpected outages, the reliability discussion is limited to a partial discussion of transmission reliability.

Technically one is correct either way using the NERC glossary of definitions. However it is a moot point that the definitional anomalies permit a dichotomous interpretation. Since this is no longer appropriate, due to the changes in the industry, specifically the increased dependence on an integrated wholesale energy marketplace and inter-regional power transactions.

As the 2003 blackout illustrated, these changes have challenged the underlying assumptions to transmission standards, many of which were developed over two decades ago. The import and export activity is no longer insignificant to the reliability of native load customers. Dispatch

[1] NERC's Glossary of Terms, Posted on NERC Website www.nerc.com/glossary/glossary-body.html> 10/31/03
[2] Ibid
[3] Ibid
[4] Ibid

control is regionally dispersed and may lack sufficient coordination for the continental power market activity.

Implications Summary

Unfortunately there is no industry consensus on transmission reliability performance metrics and the interpretation and usage of underlying definitions. Gaining industry consensus on the definition and usage of transmission reliability would improve overall comparability and accountability of the industry both externally and internally.

Multiple interpretations of the fundamental terms, transmission and reliability, jeopardize the quality of transmission reliability performance comparisons. In addition the accountability and transparency of the transmission grid operations to support the open access is at stake. Unavailability whether it is expected or not, has an impact upon the capability of the transmission facilities to support the integrated wholesale market activity, and the administration of financial instruments during grid congestion conditions.

3 AVAILABILITY THRESHOLDS

Further consensus is required with the threshold of transmission facility unavailability. Regionalized interpretations are prevalent as evidenced by multiple definitions advocated in global markets. It was evident from this project's workshop participants that there is diversity in the opinion on this subject. The effect of this undermines the comparability and transparency of industry's transmission reliability performance both externally and internally.

Industry Interpretations

During the project workshop an informal survey of availability thresholds was conducted. Participants were asked to indicate agreement to the criteria that would best describe what constituted transmission facility unavailability. Participants were given the following choices:

Abnormal condition
Defect Condition
Below Design Basis
Incapable of Full Operational Function
Less than Functional Configuration
Market Impact (LMP, FTR, TLR)
Insufficient Schedule Notice
Impacts Load Capability
Impacts System Flow
Interrupts System Flow
De-Energized Equipment
Disconnected Equipment
Load Interruption
Customer Interruption

There was not an overall consensus on this subject. In general almost all consented that unavailability occurs when equipment is disconnected, and certainly when load or customers are interrupted. Interpretations start to diverge as criteria moves toward the upper selections. Some systems already report unavailability when the configuration is changed to less than full design, i.e., an open line terminal breaker. Yet others consider only forced outages within the scope of unavailability.

Factors such as market maturity and industry segment, i.e., vertically integrated vs. transmission-only appear to some influence in the interpretation of this threshold. So how comparable and insightful are availability and reliability benchmarking results when each system has a unique interpretation of unavailability?

Implications of Application

Maintenance effectiveness and asset management optimizations rely on industry benchmarking as first step in establishing performance improvement targets. Regulatory rate decisions and cost allowance analysis also depends on the comparability of the system reliability per unit of maintenance performed. Availability of transmission facilities is of strategic importance to the increased utilization of existing transmission assets, to support increasing import and export transactions, and to the balance sheets of a consolidating industry to reduce variable maintenance costs.

System availability optimization therefore is a balance of competing interests, and improving the decision making will require a consistent approach to the system reliability reporting methodology in order to facilitate comparisons to similar systems with comparable maintenance policies and practices. Inconsistent availability criteria thresholds permit misleading conclusions when generally proactive maintenance practices are compared to generally reactive maintenance practices.

An example of this type, consider when one company performs some investigative maintenance procedure for an equipment defect that results in facility unavailability. Another utility, with a comparable system, may have neither the capability to detect such defects nor a maintenance policy that would require such utility response. Proactive maintenance may result in lower short term availability yet higher long term reliability, due to less equipment failures, forced outages, and protracted durations. Short term availability differences could be negatively misinterpreted.

Under the California ISO rules, unavailability is assessed if actions impact system flow. In addition forced outages include outages that have insufficient notice prior to the outage as well as including delays that extend unavailability beyond scheduled hours[5]. Despite the validity of arguments for or against this criteria usage, the existence of written criteria permits a consistent basis for comparison.

Availability Threshold Summary

In the absence of such consistent criteria, individual interpretations can be applied to exclude facility conditions or planned outage events from the availability picture. Establishing consistent objective criteria for unavailability is a necessary step toward comparability of system reliability, availability, maintenance effectiveness, asset management, operations, work management, and regulatory policy. The usage of objective unavailability criteria is also a necessary step to ensure the transparency and accountability of transmission operations to support non discriminatory and competitive markets.

[5] California ISO, Classifying Forced Outages, Maintenance Procedure No. 5, effective date 9/7/00, section 5.5, page5-5.

4 APPLICATION OF RELIABILITY METRICS

The application and use of transmission reliability performance metrics and performance data is widespread in the electric power delivery industry. Improving the precision of the definitions and interpretation of these data driven tools will impact all major areas of power delivery management.

Strategic Planning

Power delivery strategic goals commonly contain reliability targets which are interrelated with customer satisfaction and financial targets. Clear and concise strategic targets improve employee satisfaction and their ability to support the goals. Reliability performance goals require consistent interpretation to ensure proper goal setting against industry peers. Consistent interpretation ensures quality data collection processes to support the strategic planning process.

Maintenance & Asset Management

Asset management and maintenance goals utilize reliability, availability, and utilization data to establish management policies and guidelines for optimization. Benchmarking against industry performance is an initial step in these cyclic processes. Asset management and maintenance policy decisions use performance metrics to optimize corporate industry performance against strategic targets and regulatory concerns.

Determining best practices in the areas of maintenance effectiveness, both cost and reliability, and work management efficiencies requires industry consensus on reliability performance definitions and interpretations. Maintenance strategy decisions such as Reliability Centered Maintenance (RCM), interval optimization, and maintenance task selection depend on consistent industry consensus on reliability performance metrics.

System Planning

System planning utilizes reliability performance data to assess system adequacy and security. Reliability data is the basis for contingency analysis in probabilistic or deterministic planning studies. Contingency analysis is weighed against design criteria to identify system planning capacity improvements and capacity additions. Planning criteria assumptions used in contingency analysis models would benefit from the analysis and validation of actual system conditions against planning contingency assumptions. Consistent definitions and interpretation of underlying definitions improves the accuracy of planning processes to achieve system adequacy and security objectives.

Operations

System operation depends on the quality of system planning analysis and use of accurate and consistent reliability performance data and metrics to stay within operational guidelines for the safe and secure operation of the power system. Outage coordination and scheduling decisions must optimize the risk between customer demands and system maintenance and construction to ensure the continuity to customers and the reliability of the grid.

Reliability

Reliability management depends on quality reliability performance data collection that is consistently defined and interpreted. Accurate worst performing facility identification and prioritization depend upon the data to achieve strategic and regulatory targets in a cyclic process.

Regulatory

Traditional rate making, reliability rule making, and performance based rate making decisions depend on industry consensus on reliability performance definitions and metrics. Fair and responsible decision making is afforded from these pre requisite requirements.

Market Participation

Energy market participation, risk management, energy portfolios, import dependency, export capability decisions depend on the analysis of the quality of underlying transmission reliability performance data and metrics. Administration of a competitive and nondiscriminatory market depends upon clear and concise reliability standards and performance metrics.

Summary

Transmission reliability performance metrics are key indicators in almost every significant power delivery management decision process. Improvements to the quality and clarity of these indicators have widespread industry and societal benefit.

5 TAILORED COLLABORATION PROPOSAL, 2004

Purpose

This project is intended to standardize transmission availability metrics and increase between system comparability through collaborative development of definitions and data methodology. This project will develop the fundamental theory including: underlying definitions, metrics, and data methodology for the comparison of transmission and substation equipment performance. The direct linkage of asset performance and specific equipment availability to overall system performance will enable all stakeholders to improve business and public policy decisions.

Project Overview

The project will summarize current asset and equipment reliability performance levels (and benchmarks) and will recommend future metrics for transmission lines, substations, and substation equipment that enable all stakeholders to improve business and public policy investment and maintenance decisions in the transmission and substation arena. The expected outcomes of this project are:
(1) Comprehensive assessment of industry wide reliability benchmarks and available metrics for transmission and substation assets.
(2) Broad consensus of utility managers, system operators, and regulators necessary to approach availability targets in a performance based rates environment.
(3) Improved asset management and maintenance management decisions through enhanced linkage between grid equipment strategies and system performance measures.
(4) Improved comparability for all stakeholders of grid equipment availability between systems.
(5) Increased accountability and accuracy in the interpretation of equipment availability impacts upon grid capability.

The project will include participant workshops and surveys to facilitate consensus and expose variability regarding major equipment categories, equipment conditions and states, unavailability impacts, root causes, and restoration. Metrics and benchmarks will be surveyed, discussed, and approved by consensus through participant workshops, on site assessments, data sampling, and participant surveys.

Project Objectives

Enlist and engage sufficient commitment of North American system participants (minimum ~25% market participants or 25% of network circuit miles) in the collaborative development of standard transmission availability metrics and underlying definitions for data collection.

Enlist and engage sufficient staff personnel from industry organizations including but not limited to regional reliability councils, independent system operators, regional transmission organizations, and public service commissions.

Define metrics for the measurement of transmission network availability for use as decision support evidence from regulatory, market, and customer service perspectives.

Obtain and secure the commitment of appropriate industry technical standard organizations and policy organizations that may include but is not limited to: NERC, IEEE, NARUC, CEA, etc., to secure commitment as direct funding, staff participation, letters of intent toward ultimate adoption, or through other mechanisms of support and commitment to the development process and ultimately endorsement through their own organizational processes.

Define the objective criteria to establish a succinct definition for "transmission". Define the criterion that establishes "availability" of transmission facilities, thus what events are reportable under an availability measurement methodology required for availability metrics. Define exclusions (if any) and the basis requirements for application.

Identify transmission network performance attributes that will not be included within the scope of the project i.e., delivered power quality, system stability, system security, or system adequacy.

Provide guidelines for the development of unit, component, and equipment level application. Define the limitations to the use and comparability of the metric(s) as it may be applied to network units, components, or delivery points upon the network systems.

Perform on-site audits of data quality for forced outage root cause analysis, planned outage scheduling, switching, and operational data. Perform sampling and testing of metrics and data collection formats to assess viability through participant sampling and validation testing across the participant base.

Summarize the project results including the level of consensus upon transmission availability metrics, data testing, and standardized collection formats within 9-12 months, based upon the expectation that NAERO will be established in that timeframe approximately. Define compliance measures for percentage participation across North American systems and regulatory environments.

Project Activities

- Participant workshops.

Participants will engage in facilitated activities and focused discussion designed to explore the diversity of practices, needs, and capabilities. Participants will identify common consensus upon: (1) available, valuable, and actively measured metrics and benchmarks, (2) desirable future metrics and benchmarks, and (3) appropriate metrics and benchmarks for meaningful performance based incentives or rates.

- Workshop results.

Workshop results will be summarized and distributed for participant review after each workshop.

- Data sampling and site assessments.

Data sampling and participant site visits will be conducted to assess current practices, performance levels, and data collection capabilities for current and future metrics and benchmarks.

- Survey assessments.

Surveys will be conducted to establish current levels and practices. Existing and recommended metrics and benchmarks will be evaluated for usage, feasibility, and desirability using surveys where workshop participation is impractical for participants and industry input.

- Final draft report.

The final Functional Requirements report will be distributed to all participants and will include the summary of all workshop results.

Benefits

Transmission owners will benefit from the increased comparability of transmission availability which will result from this project. Increased comparability will enable better optimization decisions and better reflect the social and economic dependence on these vital assets.

Increased comparability will result from exploring and resolving the diversity of practices that exist today within this area today. The current state of measurement practices represents a patchwork that contains significant differences in key areas such as basic definitions and allowable exclusions.

The regulation of transmission, if it occurs, and the development of performance based rates will be improved through the standardization of the availability metrics, data methodology, and through the collaborative development from broad participation within the industry.

The value of benchmarking, which is a significant cost both in money and human resources, will be improved through the results of this project.

The value of corporate goal setting processes and compensation incentive schemes will benefit from this project since it typically relies upon benchmarking results.

The value of maintenance and operational scheduling will be improved due to the greater understanding of unavailability impacts to transmission operators and users.

The understanding of unavailability costs to the transmission owner and to market participants will be improved through the collaborative development from broad participation within the industry.

In addition grid reliability is a subset of transmission availability and will also benefit in a similar manner as has been described above for transmission availability.

The value of reliability root cause analysis and its role in maintenance, planning, and design will be improved through the insights of this project.

The value of data collection processes and information technology investments within this area will be improved through the results of this project.

All transmission stakeholders will benefit from this project as other transmission attributes may be considered for collaborative development in the future in a similar project or process.

A 2003 PROJECT ACTIVITY

In summary the activity over 2003 can be itemized as:

2003 Project Activity Timeline

1. Initial Tailored Collaboration (TC) Marketing Opportunity (Jan-Mar)
2. Initial Working Group Meeting & Feedback, Detroit, MI, (May 19, 2003)
3. Perform Basic Research of Transmission Metrics abroad (May-Aug)
4. Establishing the Working Group List Server and FTP technical requirements (Jun-Aug)
5. Industry Marketing for Project and List Server Participation (Jul-Aug)
6. Workshop Marketing, Sponsorship, and Participant Recruiting (Aug–Oct)
7. Workshop Facilitation Preparation & Planning (Aug-Oct)
8. Workshop Meeting, Chicago, Illinois (October 16-17, 2003)
9. Workshop Results Summary & Final (2004)TC Marketing Opportunity proposal (Oct-Nov)
10. Final Report Preparation (Nov) The workshop identified previously unstated project participation, pricing, and scope requirements. A revised Tailored Collaboration Opportunity proposal was distributed to participants and the list server community.

The project activity can be summarized as: growing the participant base, defining participant objectives, focusing the project scope, and identifying participant deliverable requirements.

Initial Directions

The initial TC Marketing Opportunity was issued in March 2003; however it was based upon limited feedback. The premise of the TC Opportunity was to establish data collection similar in ways to Canadian Electric Association's (CEA) transmission equipment forced outage method. This premise lacked appeal because many managers, unfamiliar with this method's format and usage, could not gauge resource requirements. In addition (1) the pricing was too high and thus counterproductive to participation requirements needed for broad consensus; (2) the scope was not aligned with specific industry demand.

The first Working Group Meeting in May was intended to solicit feedback and gain committed participants, but the project lacked a mechanism to efficiently communicate with potential participants. As a result, two main objectives were pursued based upon that meeting: (1) utilize a list server to market the project and establish and identify the community of interested professionals, (2) perform some basic research on transmission performance metrics that were already in regulatory use, as an alternative to "reinventing the wheel" in the United States and as a counter proposal to the level of detail proposed in the TC Opportunity.

Incorporating Feedback

The performance metrics research was conducted through inquiry, correspondence, and basic research of industry sources. The research illuminated metrics adopted in transmission regulatory environments throughout the world, indicated where improvements to transmission performance metrics were actively in stakeholder discussion, and identified organizations with interest in the project. The summary results of the research were posted to the list server site.

The list server site was established on EPRI's IT technology platform as the mechanism to communicate with interested professionals. These professionals were initially contacted by phone or by email. Participants were encouraged to post a brief introductory email to the group stating their interests, company affiliation, and desired outcomes for the project. This activity was ongoing during July through October as the participant membership grew from approximately 30 individuals from 15 organizations to 100 individuals from 50+ organizations in that time.

October Workshop

Phone conversations and follow up correspondence was performed during this time and was the basis of the technical content of the Workshop, held in Chicago, October 16-7, 2003. The Workshop agenda included presentations from a cross section of industry professionals from utilities, both investor-owned and public power entities, vertically integrated and transmission only, reliability councils, independent system operators, and state public service commissions. In addition several facilitated activities were completed. It was successful and well attended by 30 participants from 25 organizations; results were posted to the list server & FTP site.

The results of the Workshop were incorporated into the TC Opportunity for 2004, including deliverable requirements, participation objectives, standard organization objectives, and project pricing. The Project is slated to begin January 1, 2004.

B WORKSHOP RESULTS

Summary

An industry workshop was held for this project in October which was attended by individuals from twenty five organizations including utilities, independent system operator, regional reliability council, and state public service commission staff. The purpose of the workshop was to discuss the specific issues and interests of the group in subject matter of this report.

Eight presentations were given by individuals from a cross section of industry segments. Facilitated discussion and exercises completed during the balance of the one day session. The results of those group activities are documented below. Groups assignments were rotated between exercises. Baseball naming references were used to assign those individuals to groups.

Group Discussion Exercise #1

Summarize briefly what was heard from the individual presenters:

Motivations	
Standardized data collection model Keep it simple National/North American perspective/scope Proactive Performance based rates activity Standardized definitions Customer oriented Load Serving measures exist but Network measures are missing Provide linkage to actions that improve reliability Quantify feedback for incentives to	

improve reliability Timely data collection Improve (organizational) communication of reliability results (internally and externally) and understandability of metrics	
Existing Measures Usage	Gaps
Customer delivery metrics: SAIDI, SAIFI, FOHMY, ASAI, LNS, CCPI, DPUI External comparisons: SGS -TACS, "benchmarking communities", Southern Co., ITOMS, PA, EUCG CEA component level metrics generally unused/unfamiliar to US systems Network metrics: LMP, loss of generation due to transmission unavailability Loss of load, un-served energy	Overall Transmission network metrics Compliance of systems utilizing a given collection/ measurement methodology Analysis gaps Data plentiful; little information Lacking decision support Balance financial and asset concerns/view Misuse of measures Stated bounds needed on application of metrics Voltage at delivery point compliance Thermal compliance
Desired Outcomes	Future Usage
#1 Priority of focus	
good business decisions define purposes of measures Component level measures later priority Establish performance of existing assets	

Social outage value	

Group Breakout #1

1. How is "Transmission" defined? What realm or criterions are appropriate to establish a definitional basis? How should "Transmission" be defined?

IS defined as: (1st base)
Without transmission the industry would be a distributed generation environment, generation sited adjacent to load. Point to point delivery ; Transmission Company does not know or care who is at either delivery point, Transmission is contracted to pickup and deliver a block of energy
Appropriate criterion: **NOT:** distance, customer **Could be:** voltage
Should be:Regulated for performance and open access; Reimbursed for true costs

IS defined as: (2nd base)
Transmission of bulk power.
Appropriate criterion: Voltage level. Should be: 69kv and above for transmission performance. The 35kv and 44kv sub-transmission systems are included in the transmission impact on distribution SAIDI.

IS defined as: (shortstop)
Voltage class and FERC accounting uses functional role of facilities. One example is: EHV as 230 kV and above and the HV is less than 230 kV (Do you benchmark on the whole system versus by voltage class (kV)) (State and Federal regulators drive inconsistency between utilities for defining transmission.)
Appropriate criterion: FERC and State regulators that define the functional criteria of the

electrical facilities.
Should be: Transmission is defined as the electrical facilities that deliver energy from the generation facilities to the load centers for distribution to the energy users. The functional criteria can be defined by voltage classification and the intent of the delivery facilities.

IS defined as: (3rd base)
Each organization individually defines it for their system.
Appropriate criterion: Distribution test (7-factor test). Is it a network? By voltage level.
Should be: By voltage level (possibly 69 kV and above) with sub-categories (but don't include 69 kV with EHV). Using anything other than voltage class makes the choice too subjective.

IS defined as**:** (catcher**)**
>= 69kV
Appropriate criterion: Simplicity ; Operational Relevance ; Regulatory Umbrella
Should be: System Functionality ; Network Capability ; Delivery System Components ; Social Value ; Quality Expectations

Group Breakout #2

2. From what perspective is transmission reliability defined? How should it be defined?

IS defined by: (1st base)	Should be:
Transmission reliability is defined from a variety of perspectives and depending on your view point. Operations, regulatory, owners, customers, etc.	Transmission reliability needs to recognize the difference of the transmission systems. The system reliability needs to accommodate the bulk delivery system, network systems, and load serving. Frequency, duration and impact or magnitude for each transmission event should be part of the reliability definition

	of the delivery system type.

IS defined by: (2nd base)	Should be:
Availability of service appropriately balancing the impacts associated with the different perspectives.	Defined by standardized metrics & consistently available performance criteria.

IS defined by: (shortstop)	Should be:
Customer most common	Balancing generation to meet customer load with efficiency, reliability, quality, security and at optimal competitive cost

IS defined by: (3rd base)	Should be:
Transmission Owner and specifically the Maintenance organization. Distribution Organization as a "customer"	Regulator perspective in addition to the ones in the 'IS'. Regulators should solicit utility input. Regulators will be concerned with complaints by Generators and industrial customers.

Group Survey 1

3. What is meant by "<u>Reliability"?</u> What is the scope of transmission performance measured? <u>Events:</u> What types of events included within the scope of "reliability": outage events, thermal events, voltage events, stability events, etc.?

LANGUAGE/JARGON	Within Scope	Outside Scope
Reliability	Outage events	
Availability	Planned and unplanned	Partial transmission availability consider later
Security		Consider later

Power Quality		Consider later

Group Breakout #3

4. Current Specific Practices: What is used in your system and market?

MEASUREMENT ITEM	USED (1st base)	
	Internal/Within System	External
Definitions	IEEE and internal	IEEE, state specific (e.g. PBR), benchmarking requirements
Measures	SAIFI, SAIDI, SAIFI-S MAIFI, # loss of supply incidents, # loss of generation incidents, lost customer minutes due to transmission events (proxy for load not served), CAIDI, CAIFI, ASAI, ITR, MTBF, Circuit Importance factor	SAIFI, MAIFI, CAIDI, state specific
Exclusions	Executive discretion	IEEE definitions but may vary with regulator

MEASUREMENT ITEM	USED (2nd base)	
	Internal/Within System	External
Definitions	Metrics document: sometimes as part of incentive program	Metrics document
Measures Depending on Company	System Average of Trans Availability ISO-TLR's	Ditto Not TSAIFI or TSAIDI

	TSAIFI TSAIDI CAIDI Load not served	
Exclusions	Major Storms	Major Storms

MEASUREMENT ITEM	USED (shortstop)	
	Internal/Within System	External
Definitions	Momentary vs Sustained, Forced vs Scheduled, TVA – SID Guidelines	IEEE
Measures	LNS, CCPI, Generation Events, SAIDI, SAIFI, MAIFI,	TACs,
Exclusions	140 MWhrs of LNS in 24hr Period, IEEE Major Event – 10% of customers for 24hrs, Customer/distribution initiated outages	SGS uses six sigma, EUCG – cap outages 48 hours duration

MEASUREMENT ITEM	USED (3rd base)	
	Internal/Within System	External
Definitions	For momentary outages (e.g. less than 30 sec., 60 sec. etc.); restoration (both ends of line in-service, all breakers in)	
Measures	Availability, SAIDI, SAIFI,	
Exclusions	Transformers, radials.	

MEASUREMENT ITEM	USED (catcher)	
	Internal/Within System	External
Definitions IEEE ; ANSI ; SGS ; PA Consulting ; EUCG ; Reliability Councils ; State Regulatory Commission Requirements ; NESC ; NEC	SAIDI, SAIFI, CAIDI, Availability, FOAMI, Transformer failure rate ; Correct Operations Rate ; Mean Time to Fault ; Mean Time to Restoration ; Recent time between failure	SAIDI, Regulatory / Regional Reliability Outage Info Required ; Sometimes NONE
Measures	System averages; medians; parts of system in some cases	
Exclusions	Beyond system design criteria ; storm days / normalization @ 6 sigma level ; storm classification 3&4	State specific PUC requirements

Group Survey 2

5. Defining Outage, Interruption, or Incidents: On what basis is a transmission event reportable?

Chart Examples given:

Abnormal condition

Defect Condition

Below Design Basis

Incapable of Full Operational Function

Less than Functional Configuration

Market Impact (TLE, LMP, FTR)

Insufficient Schedule Notice

Impacts Load Capability

Impacts System Flow

Interrupts System Flow

De-Energized Equipment

Disconnected Equipment

Load Interruption

Customer Interruption

<u>Reportable responses</u>

Load interruption, customer interruption: all in agreement.

Market Impacts: mixed response, although unanimously important.

Two terminal lines with open breakers reported as unavailable by some but not all.

Inconsistency exists in unavailability/ reliability duration reporting due to interpretation and rules between systems.

Planned outages with no customer outage: treat them also as a separate measure, useful for resource allocation, crew availability, staging, etc

Available for maintenance outage - another metric?(ability of system to permit unit outage)

Are proactive practices negatively portrayed in availability measures by differences in participant risk tolerance?

Group acknowledges differences in practice can be mis-interpreted. Basic agreement exists on the difference between reliability reporting vs. availability reporting. System differences and practice differences will have tangible effect on reliability and availability metrics (even when consistently reported between systems); although results lag the practices. More redundant systems will shield the impact reliability metrics; however availability may appear lower, especially with more conservative maintenance practices.

Group Breakout #4

(NOTE: skipped. Insufficient time to complete)

6. Examining exclusions

Why are some things excluded? What is the rationale behind the exclusion? Does it still make sense? Is it impeding comparability or reliability measurement?

Group Survey 3

(NOTE: skipped. Insufficient time to complete)

7. Are planning and operating criteria in close alignment? Are operating conditions exceeding planning assumptions? Are individual utility planning and modeling assumptions broad enough for today's actual operating conditions and market realities? What measuring enhancements are needed to assess the risk of worst case scenarios?

Additional Information:

1965 NY blackout, 1977 NY blackout, 1994 Ontario Ice storm blackout, 1996 West Coast blackout, 1998 ECAR close call, 2003 Northeast North American blackout, 2003 London blackout, 2003 Sweden blackout, 2003 Italian blackout

Group Breakout #5

(NOTE: skipped. Insufficient time to complete)

8. Identify and Categorize existing and "new" potential options of:

Input Measures; input design standards, i.e., n-1, transmission, n-0, distribution, n-2, critical loads such as national security, banking and commercial markets, or urban central business districts; load block input requirements; or "critical infrastructure" input requirements

System reserve requirements (Minimum reserve cover, projected assessment of system adequacy, PASA)

Output Measures; i.e., frequency and duration of interruptions or service quality events to individual customers (DPUI)

frequency and duration of interruptions to the customer base (SAIDI, etc)

system capability measures, i.e. frequency, duration, and quantity of gap (shortfall) between network load demand and load capability

frequency, duration, and quantity of required network reserve capacity (duration and magnitude below reserve threshold(s), reserve at daily max demand, etc)

Group Survey 4

9. What participation options are practical for meeting participants?

EPRI members Tailored Collaboration (50% EPRI fund matching) YES

EPRI non-member Tailored Collaboration (100% non-member funded) YES

When are the deliverables needed? 6-12months

How often and in what formats can collaboration be effective? All below

Off-site group working meetings – semi-annually, quarterly, monthly

Web-teleconference meetings - quarterly, monthly

List server group scheduled exchanges – quarterly, monthly, weekly, as often as necessary

What resources are estimated to be required?

Dedicated participants YES

Dedicated consultants or independent facilitators? YES Add value? YES

What is the value to participants? All below, quantity unknown

Reduced benchmarking costs? Reduced internal goals process costs? Reduced regulatory management costs? Proactively influence performance based rates? Existing regulatory prudence benefit?Corporate competitive advantage benefit? (Merger and acquisition environments) Within company business unit perception? (Boss' job performance) Your job at performance? Professional curiosity?

What activities are of interest within the scope of the project?

Collaborative development of industry standard: (1) measures, (2) definitions, (3) exclusions YES

Collaborative discussion of industry practices for internal use: goals, incentives, process design

Industry benchmarking, data collection and comparison Only beta testing, method validation

Database development for industry collaboration   no, maybe future

Database discussion for internal development   no

What level of granularity is desired? Overall system level with ability to relate to unit levels

Component level brks, trfs, unit line rates) predictive modeling use, PRA future phase

Unit level (lines, protected zones, etc.): resource prioritization, maintenance effectiveness

System level measures: SAIFI, ASAI, etc. between system benchmarking

Individual Customer level: DPUI, LNS,etc. negotiated customer agreements

Market Level: TLR's, redispatch, system notices market availability & non-discrimination

Regional Level: system operating limits NERC compliance monitoring

Internal corporate level (holding company use): sibling company comparability, incentive payouts

Regulatory measures: rate decisions, management audits, rate recovery

What are the sensitivities for price and participant basis?

Pricing	Participating Systems Base	Required Input ALL, plus std bodies
$50k	10	Transmission Owners
$40k	20 minimum	ISO/RTO's
$30k max	30	Reliability Councils
$20k	40	State Regulators
$10k	50	FERC

Group Comments:

Approach NERC Regional council

6months to 1 year time frame project

Continue List server utilization

Webex teleconference forums between workshops (or monthly)

Workshops quarterly

Start with a few utilities

Consider multiple participation levels: core group, advisory, information outage data participants

Present to NERC planning committee

Rename project “Transmission Grid Reliability Performance Metrics”

Standards are important

Collection of data should be done near the end to test and validate the methodology recommended.

Participant Evaluations Summary

Overall the participant evaluations rated the workshop very favorably. The workshop was evaluated on overall content, facilitation, presentation, facility/location, activity pace, activity content, and group interaction.

Suggestions and comments indicate that the interaction and diversity of the group were of significant note. The amount of activity was more than could be finished due to the amount of discussion taking place. Suggestions were offered to lengthen the workshop, eliminate some overlap in exercises, provide advance copies to participants, and “table” some strings of discussion to improve overall flow and efficiency.

Location response was quite diverse and subjective. Driving, congestion hassle, and cost were the biggest negatives, while others considered Chicago as “great”, or “easy to get to”.

C EXISTING MEASUREMENT SYSTEMS

In order to begin a consensus process on definitions and metrics an examination of existing methodologies is appropriate. Mature regulatory and wholesale market environments are of particular interest due to the knowledge gained during their maturity.

Comparison of approaches:
1. Australia
2. Great Britain
3. Canada
4. United States

Australia's NECA Reliability Panel

The Australian market is administered by the National Electricity Market Management Company, NEMMCO which independently administered (not for profit) the energy market through fees collected from participants since 1998. The transmission reliability reports are issued annually since 1997 by the National Electric Code Administrator, NECA. There are several metrics that are published as part of that annual report. Most notably there are several additional measures that are not reported in other markets. In general the report uses a number of metrics to capture the reliability of transmission system, the capability of transmission operations to support an integrated market, and the competitiveness of the market.

In addition to measures for the continuity of supply to customers, the Australian methodology includes input reliability measures for the energy market, such as the permissible unserved energy (USE), i.e., the annual energy of customers in any region at risk of not being supplied, should be no more than 0.002 per cent. It is the basis for calculation of capacity reserve margins. The reliability of the energy market is measured by comparing the component of any energy not supplied to customers as a result of insufficient generating or bulk transmission capacity. Since it excludes energy not supplied due to the management of transmission network security and performance, it is only part of the overall measure of continuity of supply to customers.

The annual reliability report summarizes the frequency, duration, and magnitude of forecast and actual reserve margins below the USE standard. The output format is in tabular and graphical format at daily maximum demand.

The adequacy of the system and the planning processes to identify system adequacy improvements is measured by the NECA also. Projections for short and medium term adequacy compare the demand forecast against the actual maximum demand for the entire interconnected grid (the forecasts are on a 10% probability of excess (POE) basis).

Bulk transmission system (interconnector) availability is measured and reported as total outages "(only primary plant outages (affecting load carrying capability) are included, scheduled outages with less than 4 days notice, and Forced outages "(Outages not previously notified to NEMMCO, including failures and amendments by TNSPs [transmission network service providers] in response to unforeseen extreme conditions.)".

Additional performance measured includes trading interval sensitivity to demand, plant availability, and network outages. Market notice event trending, weather dependency of demand forecast accuracy, short term demand forecast accuracy, accuracy of pre-dispatch. System security performance is measured by reporting the number of frequency excursion events, their duration, and the underlying root cause contingency categorization.

In summary the Australian methodology is comprehensive and utilizes both input measures and output metrics to evaluate the reliability and capability of the transmission system and its management to ensure continuity of supply to customers and nondiscriminatory access to its participants. The assessment of transmission reliability includes objective criteria to define the threshold of unavailability. In addition forced outages by definition include criteria to include those with insufficient notice.

United Kingdom's Ofgem

In Great Britain the government regulating arm for electric utilities is the Office of Gas and Electricity Markets (Ofgem). All licensees who operate transmission or distribution systems are required to report performance annually to Ofgem. The main focus of the measurement is toward the end user. The deregulation and privatization of the electricity business has been underway since 1991. Ofgem's main focus is on creating incentives and performance targets for distribution network owners (DNO). There are changes occurring even today as some of the reporting responsibility is transitioning to other customer regulatory bodies.

Ofgem has two main sets of service measures: overall measures of the quality of service and guaranteed standards (GS) and overall standards (OS) of performance. The OS's require that average levels of service exceed a minimum. The GS's set service levels that must be met in each individual case and failure to meet this level requires a payment to the customer roughly equal to 50£. The overall standards of performance are geared toward worst served customer improvements and customer facing issues (call center, new business connections, etc.).

The overall quality of service measures include annual frequency and duration measures and accuracy of reporting performance measures, which are assessed by audit. The overall quality of service measures are more traditional vertically integrated utility system performance measures (SAIFI, SAIDI).

Transmission contributions to distribution customers are historically low due to system design redundancy. Nevertheless Ofgem reports by voltage source contribution the percentage of customer interruptions and customer minutes lost. Transmission providers supply annual reports that state the annual availability of their transmission system, estimated unsupplied energy, and average incident unavailability duration.

Some of the unique features of this measurement system are the following:

A. A distinct distribution customer (connected end-users) focus.
B. Written definitions for many terms and events; exclusion policies for events & conditions.
C. System customer, load, transformation, voltage class, construction, and service territory data.
D. Ten years of key quality of supply statistics in aggregate and by system and operating division.
E. Specific customer centered performance measures in addition to traditional utility metrics.
F. Voltage class and equipment construction sub-categorization (distribution to generation span).
G. Data accuracy performance targets, assessed through regulatory audits.
H. Fault rates per 100km of circuits.
I. Planned interruption connected customer impact.

This measurement system is the primarily end customer focused but also employs the use of widely used per unit voltage class metrics. The Ofgem model provides DNO profiles that permit interpretation of results based upon the diversity of customer bases, service territory, load density, customer density, overhead vs. underground construction, and voltage class differences between systems. The focus of unavailability is centered upon the continuity of supply to distribution customers.

Canadian Electric Association

Canadian Electric Association (CEA) has been in existence since 1891. It began to collect statistics for electrical generation, transmission, and distribution equipment in 1975. The transmission data has been collected since 1978. CEA published its sixteenth Forced Outage Performance of Transmission Equipment report for its members in May 2003 for the period between January 1, 1997 and December 31, 2001. The CEA has ten member utilities participating in the Equipment Reliability Information System (ERIS). The results are summarized for members for between system comparisons. Confidential results are supplied to each utility for within system analysis. The scope of the reporting covers transmission equipment with an operating voltage of 60kv and above. There are nine Major Component categories which are reported. It does not cover SF6 equipment except circuit breakers or DC equipment.

Some of the unique features of this measurement system are the following:

A. A distinct equipment level focus and granularity.
B. Written definitions in a complete glossary of terms.
C. Policies and guidelines for equipment categorization, such as voltage classification rules.
D. Transmission equipment inventory.

E. Summary Major Component statistics by km-years, terminal years, and component years
F. Rollup and drilldown capability of simple measures with sub-categorization structure.
G. Policies for the categorization and assignment of outages and failures to equipment.
H. Voltage class and equipment construction sub-categorization structure.
I. Use of median and mean statistics, recognizing the skewness of T&D data.

The advantages to this measurement system are its equipment specific data focus the amount of historical data. The approach is particularly good for equipment based maintenance effectiveness evaluation. The per-unit structure is one that permits the evaluation of long term trends as the asset base grows. The statistics are drawn over a significant period of time now approaching the long lifetimes of utility assets. The distribution of equipment age and design within any category would tend to make the data very robust and would be beneficial in evaluating trends and differences of specific subsets of asset populations.

A disadvantage of this measurement system is that the equipment focus disaggregates system level performance and may not align with US utilities where unit aggregation is common.

United States

Regulation

The US has no federally mandated transmission measures; however several states and ISO's have features that begin to approach elements of previous models. Statewide reliability regulation has increased as US electricity deregulation has evolved. Several states have annual reliability reporting requirements that share similarities with Ofgem. Traditionally transmission regulation has not been the primary focus of state public utility commissions, but recent events change this.

Some public utility commissions such as California have moved beyond overall statistics and examine maintenance practices. For US state or federal regulators considering prescriptive maintenance standards there are few non proprietary equipment reliability sources available that would improve the regulation decision making for transmission providers.

Regional Organizations

Market performance monitoring is commonly done by ISO's to assess market health, competitiveness, and open access. Several ISO's and reliability councils already collect and report control area statistics. Each of these has their own charter hence there is no uniform standard for transmission network performance measurement. For example system availability is uniquely measured within the California Independent System operator under the guidelines of the Transmission Control Agreement using statistical control charts of voltage class Transmission Line Circuits.

Independent Benchmarking Formats

Various equipment statistics are tracked by individual benchmarking service providers as well as ad-hoc surveys by associations and organizations. Since many of these comparisons are annual and participation is discretionary (participants drop in and out), some of these formats lack rigorous per-unit statistics (number of outages/ terminal or component years), a capability provided to CEA members in the ERIS database or by long standing mandatory submissions to UK's Ofgem.

Comparison Summary

It would be beneficial to leverage the strengths of several of the existing worldwide measurement systems in order to create comparability for utilities against world class providers. Even simple conversions have merit such as the converting the forced outage rate per hundred miles of transmission line to outages per hundred kilometers of transmission line would enable more global comparisons.

The evaluation of these existing measurement systems should be taken within the context of participant workshop demands. The following table summarizes key features of these systems:

Australia	Great Britain	CEA
Specific Transmission System Focus	Transmission's Contribution to the Overall Continuity of Supply to Distribution System Customers	Specific Transmission Equipment Focus
Comprehensive Scope of Metrics	Transmission System Customer Minutes Per Unit Network Area in Voltage Class Summary	Equipment Outages in Per Unit Per Service Year in Equipment Voltage Class Summary and Detail
Market & System Metrics	Customer Metrics	Equipment Metrics
Availability Threshold Defined	Availability Threshold Defined	Forced Outages Only (Publicly available; Members retain additional availability data on proprietary basis)
7 years of data	10 years of data	25 years of data

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About EPRI

EPRI creates science and technology solutions for the global energy and energy services industry. U.S. electric utilities established the Electric Power Research Institute in 1973 as a nonprofit research consortium for the benefit of utility members, their customers, and society. Now known simply as EPRI, the company provides a wide range of innovative products and services to more than 1000 energy-related organizations in 40 countries. EPRI's multidisciplinary team of scientists and engineers draws on a worldwide network of technical and business expertise to help solve today's toughest energy and environmental problems.

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